C8650-4

09A25 1957257 I 2057
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY
BETHESDA MD 20814

BEST AVAILABLE COPY

Volume 60, Number 11
November 1982

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

WEPCo named Electric Utility of Year

BARRINGTON, IL—Wisconsin Electric Power Co., which serves three territories in Wisconsin and the Upper Peninsula of Michigan, has been chosen Electric Utility of the Year for 1982. The announcement was made by *Electric Light & Power* magazine Editor-in-Chief Robert A. Lincicome.

The Milwaukee-headquartered utility was selected for its overall performance on behalf of its customers, shareholders and employees. Specifically, Lincicome said, WEPCo was chosen because of its strong financial performance in 1982 and for its successful efforts to rebuild its financial foundation, get long-term programs under control and put itself in a position to make decisions affecting its future based on the merits, rather than on expedition or political necessity.

A special report on Wisconsin Electric Power Company and its award-winning operations begins on page 9.

Lincicome said that the company's early recognition of changing growth trends and its success in dealing with a state regulatory commission that historically has been rated by analysts as "difficult" were important factors in company management's abilities to gain better control of its own future prospects than many other utilities are capable.

WEPCo has curtailed its construction program to the point where it anticipates no new additions until 1992 beyond the three projects now being finished. As a result, the company believes it will be able to meet 93 percent of its construction fund requirements, and 69 percent of total capital needs, from internal generation.

WEPCo's heavy emphasis on two-way communication with its publics—customers, shareholders and employees—also was rated heavily in the decision, along with the company's two-year budgeting procedure that allows rate increases to begin with the start of the target year, instead of part way through the year.

The Wisconsin utility, which serves some 2-million people in its three operating territories in the industrialized Milwaukee-Southeast Wisconsin; Appleton (WI) and Upper Peninsula (MI) areas, is the 14th electric utility to earn the award since inception of the program in 1969. Last year's winner was Atlantic City Electric Co.

Wisconsin Electric Power Co.'s Point Beach nuclear power plant, shown in a night photo above, is considered by company management to be one of the company's best investment decisions. Total production cost for the plant is 0.95¢ per net kWh, a third the cost of fossil fuel generation. WEPCo has been named EL&P's 14th annual Electric Utility of the Year.

Clinch River site work is underway, but continued funding is threatened

GAO says costs could rise to $8.7 billion

Dan Utroska
Associate Editor

WASHINGTON, D.C.—Preliminary field work actually has begun at the site of the proposed Clinch River breeder reactor in Tennessee, but the efforts of opponents to kill the project continue just as strong as ever.

At press time it appeared likely that opposition Congressmen would be able to marshall enough votes to kill funding for the project when the Clinch River appropriations bill comes to the floor of the House of Representatives during the lame duck congressional session convening after the November election.

The authorization to begin preliminary site work, granted by the Nuclear Regulatory Commission on August 5, had been challenged in U.S. courts in both Atlanta and Washington, D.C., but on September 22 the last of a spate of judicial decisions was rendered, and the Department of Energy was finally permitted to start the bulldozers moving.

The court challenge in Atlanta by the Natural Resources Defense Council was aimed at nullifying the decision by the Environmental Protection Agency in that city to issue a water discharge permit for the Clinch River site before completion of an environmental impact statement. NRDC argued before the court that the granting of a National Pollutant Discharge Elimination System (NPDES) permit before issuance of the impact statement was illegitimate.

The district court in Atlanta agreed and issued an injunction prohibiting any site clearing work. But when the Department of Energy took the matter to the U.S. Court of Appeals for the Eleventh Circuit, it was decided that the Court of Appeals for the District of Columbia Circuit was the more appropriate place to litigate the matter and so the lower court ruling was overturned on jurisdictional grounds, a spokesman for NRDC said. On September 22, therefore, the way was cleared for DOE to start preliminary construction work in Tennessee.

The Natural Resources Defense Council, responding to the court's

Continued on page 15

California PUC contemplates partial rate treatment for SCE's San Onofre-2 unit

SAN FRANCISCO—The staff of the California Public Utilities Commission is contemplating a rate scheme that would allow Southern California Edison Company to recover only about 60 percent of its investment in the San Onofre-2 nuclear plant when that unit becomes operational.

Under the plan, the remaining 40 percent would be recovered if and when an independent audit verified that all construction expenditures had been prudently incurred.

While the CAPUC proposal on base rate treatment for San Onofre-2 has not yet been offered in evidence in commission proceedings, it is noteworthy that the state agency is contemplating such an action against a backdrop of growing regulatory reluctance to authorize full, traditional rate base treatment for large baseload generating plants. *EL&P* has reported the growing desire of some commissions to alleviate "rate shock" and to confirm the prudency of the huge expenditures being incurred by

Continued on page 17

Creative funds ease deserted plant write off

SALEM, ORE—Portland General Electric company will use nearly $65 million in proceeds from a debt-equity swap to help pay for the costs of its now-abandoned Pebble Springs nuclear plant.

The move has been prompted by the interpretation of state statutes by the Oregon Public Utility Commissioner. John Lobdell says that state law prohibits the recovery from ratepayers of costs sunk in abandoned power plant projects.

In a debt-equity swap, an investment banking firm buys up numerous issues of a company's low coupon bonds, and after calculating how many shares of that company's stock will be required to offset the retired debt (factoring in some other costs), it offers the bonds for retirement by the utility in return for shares of new stock. The banking firm then turns around and sells these shares on the open market.

The utility is able, through such a deal, to pick up the difference between the face value of the retired securities and the price the investment banking firm paid for them. The utility can thereby avoid the taxes on the gains it would otherwise have had to pay if it had retired the outstanding debt on its own.

Earlier this year, the Oregon utility commissioner required Portland General Electric, principal owner of Pebble Springs at 47 percent, and Pacific Power & Light, a co-owner at 29 percent, to write off their investments in what Lobdell then called "two dry hole nuclear projects."

According to commission figures, PGE's share of the project's sunk construction costs total nearly $132 million. In addition to applying the proceeds from the debt-equity swap, the utility will put up $10.8 million gained through its leasing of federal tax credits. In addition, the company's tax liability will be reduced by $44.4

Continued on page 20

Foreign Power Briefs

• **France** will construct a plant to produce fuel for nuclear plants operating under the pressurized water reactor system. The government approved plans for the plant which will be built by Cie. Francaise des Combustibles, a jointly owned subsidiary of the state-controlled Cie. Generale des Matieres Nucleaires and Framatome, the nuclear equipment subsidiary of Creusot-Loire S.A., the heavy industry group. Completion of the plant is scheduled for late 1983. It will be located near nuclear plants at Pierrelatte and produce 1,250 tons of nuclear fuel annually.

• **Victoria, Australia's** state electricity commission will borrow nearly $3 billion over the next few years to finance the Loy Yang generation project. Eight 500 MW coal-fired turbines are to be installed by 1993. The commission has already raised about $1 billion of the estimated $4 billion needed to complete the project.

• **Britain's** Central Electricity Generating Board (CEGB) has chosen the Hinckley Point nuclear station in Somerset as its next nuclear site after Sizewell B. The CEGB is seeking approval to make Sizewell B the first British station to use the Westinghouse/SNUPPS pressurized water reactor. Hinckley C would then be the second plant to use the Sizewell design.

• **Ontario Hydro** and a group representing about 5,500 management and professional staff have negotiated a voluntary program to help cut the Canadian utility's 1982 payroll costs. Employees can choose to take an unpaid leave of absence, additional unpaid vacation time, work a four-day week at 80 percent pay, or volunteer to work additional hours without pay. The program will last until the end of the year.

• **A Swedish** electrical equipment manufacturer, ASEA AB, has announced that it is backing-out of a billion dollar power project in Zaire. Company officials report that the government of Zaire owes ASEA more than $60 million and has failed to maintain contractual payments. ASEA had asked for immediate payment of $12 million to continue with the project.

• **FERC** recently approved agreements between Hydro-Quebec and a group of eight New England utilities that will clear the way for construction of a high voltage transmission line in Vermont or New Hampshire. The New England utilities estimate that the line could save the companies about 7.5 million barrels of oil a year and eliminate the need to construct 500 MW of reserve generating capacity. They say it could be operable by 1987.

• **A group of Swedish** companies and Allis-Chalmers Corp. have combined to form Fluidcarbon Sweden AB, which will produce and market a coal-water mixture as a fuel for utility and industrial boiler applications. Developed by Swedish scientists, fluidcarbon fuel is made up of roughly 75 percent coal, 1 percent additive and water. Extensive testing has confirmed that the fuel functions commercially at a cost approximately 20 percent less than for conventional oil fuel.

• **Rhapsodie,** France's first experimental fast breeder reactor has been shut down permanently. The French Atomic Energy Commission said studies showed repairs of an internal nitrogen leak would be too "complicated, long and costly." Rhapsodie first went into operation in 1967. The Commission said the reactor "has already fulfilled its objectives."

In This Issue

Editorial 4
EL&P names Wisconsin Electric Power Company Utility-of-the-Year. A special report. 9
New material holds promise of improved underground splices. T/D 21
Calendar 25
Nuclear steam generator life can be prolonged. G 31
Old hydro plants can be upgraded to provide owners with added capacity at minimum cost. G 46
Reader Service 51
New Products 54
New Literature 60
Advertisers' Literature 65
Personnel 68
Regulatory Review 70
Resume Service 73
Management Methods 76

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

BEST AVAILABLE COPY

GAO: U.S. can't handle big emergency outages

Don Minner
Assistant Editor

WASHINGTON, D.C.—Federal and state governments are not adequately prepared to handle a major electrical emergency, says the General Accounting Office.

"The utility industry has demonstrated the capability to manage and restore service in most instances of power outages caused by accidents, weather, equipment failures, and human error," said the GAO in a recent report. "However, should the nation or region suffer a major, long-term power disruption caused by war, sabotage or terrorism, the consequences would most likely have national impact."

The GAO chastised the Department of Energy for not putting together an emergency program. "Considering that more than 16 months have passed since our recommendation that DOE develop a program, we believe DOE could have done much more," the GAO said.

In earlier reports, the GAO had urged the Energy Department to develop programs to handle national electric emergencies.

DOE protests

An official at DOE heatedly protested the way in which the GAO prepared the report. "The report speaks for itself," said Rich Weiner, director of the Office of Energy Emergency Operations, "It's an extraordinary poor work."

Weiner said that GAO sent over two "incompetent auditors who didn't know the first thing about the subject" they were investigating. He says he saw them in the operations office twice for a total of about 4 hours.

DOE has not revised its electric emergency handbook, developed or conducted any training programs and the GAO says that no substantial planning has been done.

But Weiner says the GAO did not fully look into all the plans his office is preparing. "I have a milestone schedule and all our deadlines are being met," exclaimed the director. "We are proceeding well on the different plans."

Budget cuts also will have an affect on emergency preparedness programs, notes the report. The proposed budget for 1983 is nearly half of what it was in 1982 and 22 staff members are to be dropped.

Work continues

That, says Weiner, is the only bit of truth in the report. He said his staff will be cut, but work will continue and continue to be on time.

Although many states have laws which give the governor power to act in an electrical emergency, the report says most do not have any specific plans detailing how power would be restored quickly and effectively.

"Should a major regional disruption occur, individual states would not be able to effectively handle the situation," notes the report. "...an action by one state may adversely affect another state because the electric power is not tied to state jurisdictional boundaries."

According to Weiner, individual utilities are prepared and know the best way to restore power in their systems, so the Federal government should not tell them how to do it.

"Our major problem is national defense," he said, "We are working extremely close with the intelligence community and electric utilities to determine who is capable of causing a flow-through disruption—one that endangers the defense of the country."

Out of 11 states contacted by the GAO, none had any form of plan to deal with a major electrical emergency. Florida does have a plan for statewide emergencies that was developed with the aid of a Florida utility industry group.

The GAO report points out that California, Georgia, Texas and Illinois rely completely on the utilities to handle any statewide emergency.

Attacks

Rep. Berkley W. Bedell (D-Iowa), chairman of the House Small Business energy committee, requested the GAO study the matter after witnesses testified in May about attacks on electric facilities.

Amory Lovins, the "soft energy path" proponent, testified about farmers in northern Minnesota who have shot out insulators and knocked over transmission towers because power lines were planned to run over their property.

And another witness testified of a 1980 raid on a house in New York that uncovered detailed plans of New York's electrical system.

Bedell said it is unwise to "ignore the very real possibility that simple acts of sabotage and terrorism could shut down our electric power system and bring our society to its knees."

As an example, the GAO points to the recent sabotage of a substation on Vancouver Island, Canada. The substation was still under construction, but the damage was extensive enough that the utility may have to ration or allocate power until it can be rebuilt.

"This is ridiculous," sighed Weiner, "We have the complete support of the electric utility industry and every agency we work with. I would think the GAO could find a better way to spend their money."

APS reduces '83 operating budget

PHOENIX—In an effort to reduce 1983 operating expenses, Arizona Public Service Company (APS) has announced measures to trim over $14 million from its budget.

Some of the measures were prompted by recommendations in a recent independent audit of APS' management and operating procedures.

The company said its cost control efforts will involve phase-out of some local customer service centers, decreases in personnel through attrition and early retirement.

A one-time voluntary early retirement program will be offered to employees who are at least 55 years old and have 20 or more years service with APS.

"The program will enable us to evaluate our manpower requirements, streamline our organization and reduce company expenses at a time when we are exploring every cost-saving avenue available," said Mark De Michele, executive vice president for customer, employee and corporate relations.

How to prolong steam generator life in nuclear plants

S.Frank
R.P. Wessel
W.B. Dodson
D.A. Piccione

Stone & Webster

Nuclear steam generator design life is 40 years, but replacement may be required in 10 years or less. Can corrosive failure be averted and operating life extended? This question is being asked by many utilities about steam generators in pressurized water reactor (PWR) nuclear power plants.

Defining the problem

Steam generators in PWR plants world-wide are experiencing problems that are reducing both operating life and overall plant availability. In 1981, 26% of non-refueling outage time was caused by steam generator-related problems. Practically all problems occur on the secondary (steam and feedwater) side of the steam generator tubes.

The first serious problem occurred in 1973, when severe thinning (wastage) of Inconel 600 tube walls became evident in several recirculating steam generators. In 1974, to prevent further tube wastage, the industry began switching from phosphate secondary side water treatment to all-volatile treatment (AVT), using hydrazine and ammonia. (Only AVT water chemistry has been utilized in once-through steam generators. Problems in once-through steam generators result primarily from mechanical factors which relate to internal steam generator design and which are not addressed in this article.)

But in 1975, denting of steam generator tubes at the carbon steel tube support plates was discovered. By 1979, other problems such as U-bend cracking, intergranular attack, stress corrosion cracking and pitting were found to be affecting steam generator tubes. A description of the various corrosion problems is given in the table.

Denting, which can lead ultimately to cracking of a tube, is the most serious problem encountered in steam generators to date. The major constituents in the electrochemical processes leading to the formation of nonprotective magnetite (Fe_3O_4) at the tube-to-support plate crevices are chlorides, copper, and oxygen. Since the oxide does not act as a protective layer, corrosion continues; and since the oxide occupies more space than the parent metal, squeezing, or denting, of the tube from the outside occurs.

Denting was the principal reason steam generators at the Surry and Turkey Point nuclear power plants had to be replaced. Limited success has been achieved in arresting tube denting. Chemical cleaning has yielded mixed results, while plant and operational improvements to preclude denting have proven to be costly and time-consuming.

"Replacement may be required in 10 years or less."

Most of the other problems listed in the table occur in the region just above the tubesheet where sludge accumulates, resulting in corrosion of the Inconel 600 tubes by pitting, wastage, intergranular attack and cracking. Maintaining the tubesheet region free of sludge is difficult. Plant system changes and steam generator design improvements are needed to keep the tubesheet region as free as practicable of stagnant contaminants. Stress corrosion cracking of improperly mill-annealed Inconel 600 tubes is the only corrosion problem initiated on the primary side. This problem, as well as other mechanical problems such as fretting (vibration-induced wear) and fatigue cracking may be avoided by improvements in steam generator design and fabrication.

Plugging tubes

When tube deterioration has been identified (for example, by periodic eddy current testing), corrective action must be taken. Plant technical specifications provide a limit for wall degradation beyond which tubes must be removed from service by plugging. Permissable degradation is based on the minimum wall thickness required to provide adequate structural margin during normal operations and postulated accident conditions. Plugs are installed at both the tube inlet and the tube outlet.

Large numbers of tubes may be plugged and removed from service in order to avoid steam generator tube rupture. Plugging results in a loss of heat transfer surface; however, most designs have excess surface area, so that significant reduction in plant power level occurs only after 20 to 25% of the tubes has been plugged.

"Can corrosive failure be averted and operating life extended?"

Some utilities have chosen to repair tubes by sleeving instead of plugging. In sleeving, a tube of smaller diameter is inserted inside the damaged tube. The sleeve is positioned to cover the degraded portion of the original tube, and is then expanded above and below the degraded region.

Sleeving repairs have been performed on the straight portions of tubing within and just above the tubesheet, after the tubes had experienced wastage, pitting, intergranular attack, or stress corrosion cracking. Although adequate for these purposes, such repairs are not practical for tubes affected by denting.

A number of factors must be considered before a decision is made to use sleeving for repair. The remaining life of a plant must be evaluated against the costs required to complete steam generator repair. The expected life of a sleeve must be considered also. There has not been any significant operating experience with sleeved tubes, so the success of this method has yet to be determined.

Radiation exposure to workers during installation of sleeves is a concern. For example, radiation levels on the primary side of the tubesheet have been estimated at the Ginna plant to be 21 R. Sleeve repairs were made to 6500 tubes at San Onofre Unit 1 and resulted in a total exposure of 3500 man-rem. As a comparison, exposure for steam generator replacement at Surry 1 and 2 and at Turkey Point 3 has ranged from about 1760 to 2150 man-rem.

Operation, maintenance changes

The routine operation and maintenance activities at a plant can significantly affect steam generator life and plant availability. These activities must focus on monitoring and controlling secondary side water chemistry if steam generator life is to be prolonged.

A thorough and firmly instituted water chemistry program is required. This involves monitoring key parameters at critical locations, maintaining secondary side water chemistry requirements during layup, startup, and normal operation, and evaluating water chemistry data. The evaluation must quantify benefits of techniques used to limit contaminant levels, locate sources of impurity intrusion and determine appropriate corrective action when specified limits have been exceeded.

The importance of proper secondary side water chemistry is often overlooked during an outage. Shutdown is a period of significant corrosion activity. Therefore, water chemistry must be carefully monitored and controlled during these periods, as

Continued on page 34

STEAM GENERATOR CORROSION PROBLEMS

Problem	Description	Plants reporting serious effects
Wastage (Thinning)	Reduction of wall thickness of Inconel 600 tubing in the region above the tubesheet where acid-phosphate sludge exists.	26
Denting	Crimping of tube diameter caused by progressive formation of oxides in annular region between the tube outer wall and the tube support plate.	33
Tube Cracking		
U-Bend Region	Cracks originating in region with excessive ovality, assembly stresses or improper heat treatment during fabrication.	12
Tube Sheet Crevice Region	Cracks initiated in the stagnant crevice region by corrosion mechanisms such as IGA or SCC or as a result of improper tube rolling techniques.	18
IGA–Intergranular Attack	Corrosive attack of grain boundaries in Inconel 600 tubes with no preferential (stress related) orientation.	8
Pitting	Localized attack on tubing resulting from nonuniform corrosion caused by formation of local corrosion cells.	6
SCC–Stress Corrosion Cracking	Intergranular grain boundary cracking of stressed Inconel tubes.	26

"Changes in procedures and equipment can be effective, however, they may not preclude replacement with improved designs."

Steam generator . . . continued from page 31

well as during normal operation.

Clearly, the condenser is the major potential source of air and cooling water leakage into the plant secondary side. Detection and rapid correction of condenser leaks are, therefore, essential. A short-term advantage may be gained by continued power generation when leaks exist which cause specified water chemistry limits to be exceeded; however, this advantage can be easily offset by costly long-term corrosion.

A leak detection system should be used routinely to locate air leaks. Periodic eddy current inspection of condenser tubes and preventive plugging are necessary if cooling water inleakage during operation is to be avoided. Water leaks can be found by utilizing a sensitive leak detection system with a water box drained.

Steam generator cleaning

Various cleaning techniques can be employed periodically to remove impurities from the steam generator during an outage. In steam generators with concentrated contaminants in tube-to-tubesheet crevices, low temperature depressurization flushes should be performed. This procedure has been used in the U.S. and Japan. It involves heating (by electrical resistance or reactor coolant pump heat) a volume of water just above the tubesheet while maintaining a nitrogen overpressure, then releasing the nitrogen. The resulting rapid boiling has been successful in dislodging solid and soluble impurities from the crevices.

Boric acid soaking and maintenance of residual concentrations during operation have also been used at some plants. The intent was to combat denting. Some success has been achieved, but incidence of increased pitting is now being investigated. Therefore, use of boric acid has yet to be proven, as do a variety of other chemical cleaning methods.

Water soaks at high temperature are useful in removing soluble contaminants from steam generators during shutdown. Sludge lancing has also been effective in breaking up accumulations of solids on the tubesheet and facilitating their removal.

To be effective, each of the operating and maintenance activities requires a detailed written procedure, incorporated into a regularly scheduled program, with specific operator training. Such a program improves understanding of steam generator problems and their prevention. The program also permits engineering review of considerations such as compatibility between system materials and water chemistry.

There are a number of improvements which can be made to operating plants which will aid in prolonging the useful life of their steam generators. It is anticipated that all or part of the modifications discussed below could be accomplished during a normal refueling outage.

The blowdown system removes dissolved solids and corrosion products (sludge) from the steam generator secondary side. It also removes nonvolatile radioisotopes when leakage from primary to secondary side occurs. Impurity removal is usually through a horizontal perforated tube leading to two, diametrically opposed, blowdown nozzles, located just above the tubesheet.

Controlling the concentration of dissolved solids and sludge is important in maintaining water chemistry within specification over the full range of operating conditions and thereby in limiting corrosive attack of steam generator materials.

Adequate steam generator protection requires a blowdown system capacity of 1 percent of the maximum steaming rate (MSR) for maximum continuous blowdown. This rate should be used during startup, shutdown, and upset conditions, such as condenser leaks. Consideration should be given to increasing the blowdown capability to 1 percent MSR in all plants with recirculating steam generators as a necessary means for controlling sludge buildup. In some cases, this can be done by simply opening a valve more widely, or, if the pipe size from the steam generator blowdown nozzle has been reduced, replacing it with larger pipe.

In addition to blowdown rate, heat recovery and water recovery are considerations that affect selection of blowdown system configuration and equipment. The cost of equipment to recover thermal energy in the blowdown must be balanced against a reduction in plant thermal efficiency. The cost of equipment to clean up the blowdown and recirculate it to the condensate system must be balanced against the cost of makeup water and waste treatment equipment if the blowdown is discarded.

Layup practices

Maintenance of good secondary side water chemistry is important during periods of plant shutdown, just as it is during normal operation. To protect the steam generator internals from corrosive attack during these inactive periods, the steam generator should be maintained in a wet layup condition.

Wet layup is achieved by filling the steam generator secondary side with deoxygenated, chemically treated feedwater. Since reliance on thermal currents to circulate the water within the steam generator is ineffective in providing thorough mixing of the oxygen scavenging and pH control chemicals, a forced circulation system is needed. It should be capable of circulating secondary side water so as to mix steam generator chemicals uniformly and thereby reduce corrosion.

The wet layup system has other uses such as draining and filling the steam generators. It also works in conjunction with the steam generator nitrogen system to ensure exclusion of oxygen from the steam generator internals. A low pressure nitrogen blanket is maintained above the level of water in the steam generator during wet layup.

Only a visual inspection of the interior can verify the effectiveness of steam generator-related improvements.

Inspection ports, placed to allow visual access to the critical areas of the steam generator, are relatively easy to install and should be added. Installation basically consists of drilling holes through the steam generator shell and providing closure covers for normal operation.

Inspection ports also can provide access for cleaning operations and, in some designs, can function as connection points for improved blowdown, wet layup and fill and drain systems.

Water chemistry control

AVT water quality specifications require precise monitoring and control of chemical concentrations in the parts per billion range. Relatively minor perturbations in water chemistry can cause the specified limits to be exceeded unless the plant is equipped with a precision monitoring system, a hydrazine (for oxygen removal) management system, a condensate polisher, and either a leak tight, deaerating condenser or a deaerating feedwater heater, or both. Furthermore, stringent water quality control is necessary not only during normal operation but also when the plant is shut down, in a transient condition, or operating at part load. During startup, for example, feedwater should be recirculated without being introduced into the steam generators until water chemistry is within required specificatins for normal operation.

Leakage of air and cooling water into the condenser has been a major source of impurities leading to steam generator corrosion. Condenser operation must, therefore, be evaluated when measures for prolonging steam generator life are considered.

A two-pronged approach to combat condenser air leakage is advisable:
1. Detect and plug leaks
2. Improve the deaeration capability

Typical air leakage locations are the turbine-condenser expansion joint, pipe connections and valves. Condenser deaeration can be improved by upgrading the air removal system, redesigning the tube bundles, or reducing condensate subcooling in the hotwell at partial load and during startup by heating.

If condenser cooling water leakage is found to be causing steam generator degradation, a condenser tube failure analysis may indicate the condenser should be retubed with a more corrosion-resistant material, such as titanium or a high alloy, pit resistant steel. Use of copper in the condenser, as well as in other secondary system components, has been found to promote denting in the steam generator and should be avoided. If condenser retubing is undertaken, attention must be given to considerations such as tube vibration, condenser uplift, condenser performance, galvanic corrosion and the tube-to-tubesheet joints.

Along with condenser tube failure, the tube-to-tube sheet joint has been a major source of cooling water leakage. Special measures to ensure leakage-tight integrity, such as use of a double tubesheet, integrally grooved tube-sheet, or a welded joint, should be considered.

Soluble and filterable impurities in the condensate downstream of the condenser hotwell can be removed by a condensate polisher. If condenser cooling water leakage is minor, the condensate polisher allows the plant to remain on-line while the leak is located and repaired. In the event of massive condenser cooling water leakage, the condensate polisher provides time for an orderly plant shutdown. Thus, the condensate polisher maintains the desired water chemistry under various operating conditions and reduces start-up time by providing more rapid water cleanup. Its use is virtually mandatory if the AVT specification of near-zero solids in the steam generator is to be achieved reliably.

Deaerator

Water quality specifications require very low oxygen concentrations in the feedwater entering the steam generator. A deaerating feedwater heater (deaerator) is the most effective means for removing oxygen over the full plant operating cycle, including startup and load swings when corrosion and oxide deposition reach their highest levels. Although deaerators are used extensively in PWR plants abroad, only two domestic units operating today incorporate a full-flow deaerator.

A utility considering adding such a device to an operating plant faces a major retrofit. A deaerator retrofit will increase steam generator availability and operating life because it will reduce oxygen in the feedwater. However, detailed analyses on a plant-specific basis are required to determine cost of installation and effects on system performance.

Conclusion

Prolonging the useful life of steam generators is of high priority for owners of PWR plants. This applies to utilities with steam generators currently in service, as well as to those with new or replacement steam generators about to begin operation.

Industry investigators agree that secondary water chemistry is a key element in preventing steam generator corrosion problems. Achieving the necessary water chemistry control during all phases of operation may require a program for incorporating significant improvements both in plant operation and maintenance, and in systems and components which affect water chemistry.

Changes in procedures and equipment can be effective in prolonging steam generator life; however, they may not preclude eventual replacement with steam generators of improved design in order to achieve high availability at design output.

Old Hydro plants can be upgraded to provide owners with added capacity at minimum cost

James Gasperini
Paul Johrde
Michael Costa

Westinghouse

Modernizing existing hydro plants can be an economic means of expanding generating capacity and can be extremely cost effective in today's operating environment. At current oil prices the benefit-to-cost ratio of upgrading hydro can be as high as 40 to 1. Typically, older hydro units can be uprated by 15 percent, and many significantly higher.

There are only a few ways to increase hydro plant output—by reducing penstock losses, increasing the amount of water available, raising the hydraulic head, and modernizing the turbine and generator—and some of these alternatives are prohibited by factors such as cost, institutional regulations, or environmental restrictions.

Generator modernization is usually the cheapest and easiest alternative for effecting a significant improvement in hydro capacity and efficiency. The following electromechanical areas offer the greatest opportunities for modernization: stator coil insulation, ventilation and cooling, thermal analysis, and computerized design optimization.

Stator winding replacement

The most common generator uprating modification is replacement of the stator winding, using the existing rotor winding and exciter. If the capacity of the exciter is exceeded due to the increase in field current with load, the power factor of the generator may have to be increased, or the exciter may have to be replaced.

In the example shown in Table 1 the machine had enough margin in the exciter and the rotor winding to permit the indicated uprating. The new stator winding has the same number of turns per coil and the same number of parallel circuits as the original. The epoxy-mica ground insulation has a higher allowable working stress than the old asphalt type and can therefore be made thinner for the same voltage. This allowed the designer to improve the coil in three ways: more and thinner copper strands per turn were used to reduce AC strand loss; total copper volume per turn was increased; and the use of a more complete transposition provided a further reduction in eddy loss.

Several generator characteristics are changed. The short circuit ratio is reduced by 15 percent and all reactances are increased 15 percent when referred to the new base. The exciter ceiling voltage does not change so the response ratio is lower. Since the fixed losses remain the same and the new winding has lower eddy current losses than the original, the total loss does not increase in proportion to the load and, therefore, a higher efficiency is obtained.

Thermal analysis

A review of the performance tests of generators built 20 to 40 years ago will show that most had substantial temperature margins from their guaranteed temperature rises. This is especially true of the rotor winding. Thus, by rewinding the stator using compact epoxy-mica in place of the more bulky asphalt-mica insulation and applying a more effective transposition coupled with thinner copper strands, it is usually relatively easy to gain a 15 percent uprating with the original temperature guarantee.

The original, "cool" rotor winding usually can carry the increased field current associated with the uprating. This is very fortunate because most rotor windings suffer little or no deterioration with time and are seldom replaced.

Once the uprating is determined, based on the most restrictive thermal limits of the rotor or stator windings, the new losses are calculated and the original air coolers checked to determine if the additional loss can be absorbed by increasing water flow. Often the coolers have liberal margins, which can be utilized by frequent cleaning of the tubes to minimize fouling.

Ventilation and cooling

Ventilation tests on old generators have shown that many do not have the air flowing where arrows on the drawings indicate. In fact, the velocity and quantity of air flowing in certain parts has been so low in some cases that only excessive margin in the original design has kept the machine operating. For this reason, a survey of the air flow distribution in a generator and measurements of the velocities in the critical cooling passages should be made a necessary input to uprate calculations.

It is often possible to improve the effectiveness of the ventilation system by providing a new endbell design, adding fan blades to the rotor, replacing fan blades, and directing flow to needed areas by adding baffles.

Mechanical changes

In a typical uprating, many electrical components such as stator windings are replaced with technically advanced designs and materials, but the mechanical components remain the same and are loaded under the higher rating. Certain mechanical areas must be considered in the initial planning stages of an uprating. Table 2 provides a general checklist.

The single most obvious change to the mechanical parts is due to the increase in torque which can be significant since upratings run anywhere from a few percent to well over 50 percent. Components most affected are the spider, the shaft, the stator, and the rim-to-spider and spider-to-shaft connections.

The uprate may or may not involve a change in the turbine. If a new turbine is specified, the generator designer must contend with a number of possible changes. A new normal speed, new runaway speeds, new turbine weights, and new hydraulic thrusts must all be considered as causing a significant change in the reliability of the generator.

Economic analysis

The financial analysis shown in Table 3 is based on an actual uprating of a Bureau of Reclamation unit at Grand Coulee. The technical and economic data are taken from that project but the analysis assumes investor-owned utility economics.

The generating unit had approximately a 45-percent capacity factor and had enough water available to take advantage of a 16 percent capacity uprating. The modernization included a replacement set of uprated epoxy resin high voltage coils, a loop test, refurbishment of the stator iron, and new resistance temperature detectors. Because the wheel had additional margin to accommodate the uprating, no additional turbine work was required.

This financial analysis is in accordance with the Electric Power Research Institute's Technical Assessment Guide PS-1201-SR, July 1979. The time value of money (present worth), fuel escalation, product cost escalation, and the total cost associated with ownership are taken into account. The object of the analysis is to determine the present worth savings and cost of the investment opportunity, approximate investment payback period, and cost-to-benefit ratio of the generator modernization.

The analysis takes into account several financial factors, as well as some specific facts concerning the uprating in question. These factors are shown in Table 3 as items A. through K.

First an analysis base year (the year in which delivery and final payment are made) is assumed and all costs and revenues are present-worthed to that base year at the financial discount rate. The discount

Generator uprate, Seattle City Light

The scope of a hydro generator modernization project can be illustrated by a brief description of work currently in progress at Seattle City Light's Gorge Powerhouse. The installation has three generating units totaling 33 MVA, two installed in 1924 and one in 1929. The units are being uprated to 38 MVA.

New steel core

The modernized generator equipment includes a new, low-loss silicon steel core, a newly designed core-clamping-pressure package that will significantly tighten up the new stator core, and newly designed thermalastic epoxy stator windings. The units are designed to run 10 degrees C cooler than the original units at the higher rating. Stray load losses and stator I^2R losses are being reduced by 94 kW.

At 38 MVA, 97 percent power factor, the excitation requirements will be the same as at 33 MVA, 90 percent power factor, producing no increase in field winding operating temperatures. The winding will have the capability of operating at 40 MVA, 99 percent power factor with no increase in field winding operating temperatures or excitation requirements.

The stator coil copper cross section has been increased approximately 27 percent above that in the original winding to reduce the operating temperatures and stator I^2R losses. The stator coil stranding and winding transposition have been improved to provide a significant additional reduction in stator winding operating temperatures by minimizing the eddy and circu-

Closeup of the restacked core shows pieces of hardwood wedged into the slots to keep the parts aligned.

lating current loss component of the generator stray load loss.

Locking devices installed

Stator winding connections, parallel rings, and main and neutral leads are designed to match the increased loading requirements. Stator winding components are braced with spring-type fillers in the slot wedging assembly to maintain radial pressure on stator coils even after dimensional changes have occurred in slot fillers during normal operation. Locking devices are being installed to prevent axial migration of slot fillers.

Materials improved

Improved materials and design techniques will also be used for stator core laminations, stator vent plates, stator end finger plates, the top end plate and the frame-to-soleplate connections.

rate for analysis purposes is equal to the weighted cost of capital. It is assumed that savings begin the year after delivery. Differential production cost is escalated at a constant percentage each year from 1982. Total cost ownership or value of capacity increase is determined through the use of a fixed charge rate which is applied to the investment each year of its useful life. This approximates the total costs associated with ownership which are incurred each year.

To determine the equivalent capital value of present worth savings, the levelized annual fixed charge from each is present-worthed at the financial discount rate. This value is then compared to the capital expenditure. The cost-to-benefit ratio is the resulting ratio between this comparison.

Following are sample calculations

TABLE I. CASE STUDY SUMMARY
Actual Unit Information

	Original machine	After uprating
Rotor winding	Class B strap copper	No change
Stator winding	Class B asphalt	Class B epoxy-mica
Rating	108 MVA, 1.0 PF, 13.8 kV	125 MVA, 1.0 PF, 13.8 kV
Overload	15%	15%
Exciter	400 kW, 250 V, 300 V ceiling	Same
Short circuit ratio	1.94 (C)	1.63 (C)
Gen. field current: Rated load	1,220 amps (T)	1,250 amps (T)
Rotor winding temp. rise: Rated load	33.5 C (T)	35 C (T)
Stator winding temp. rise: Rated load	51 C (T)	52.5 C (T)
Losses at rated load	1,863 kW (T)	1,910 kW (T)
Efficiency at rated load	98.3% (T)	98.5% (T)
Stator coil copper	36,080 #	37,490 #
Normal torque	75.7 x 10^6 in lbs	87.6 x 10^6 in lbs

These values are indicative for 9 of the 18 original units. The other 9 units may have different values although the uprating is the same.
(T) Test
(C) Calculated

TABLE II. GENERAL AREAS OF CONCERN FOR MECHANICAL INTEGRITY

	The components are most affected by changes in				
Major components	Torque	Speed	Short circuit conditions	Magnetic pull	Thrust
Frame	X	X	X	X	X
Stator foundation	X	X	X	X	
Core–frame connection	X	X	X	X	
Spider	X	X			
Spider–rim interface	X	X		X	
Rim		X			
Pole dovetail–tip		X			
Field coil		X			
Shaft	X	X		X	
Shaft–spider connection	X	X			
Shaft coupling	X	X			
Bearings		X		X	X
Brackets		X		X	X

TABLE III. UPRATING FINANCIAL ANALYSIS–45 PERCENT CAPACITY FACTOR

A.	Kilowatt rating (kW)	: 97200
B.	Differential prod. cost (M/kWh, year)	: 18 82
C.	Capacity factor (percent)	: 45
D.	Uprating (percent)	: 16
E.	Fuel escalation rate (percent/year)	: 8
F.	Financial discount rate (percent/year)	: 14
G.	Fixed charge rate (percent/year)	: 18
H.	Analysis base year	: 82
I.	Economic life (years)	: 25
J.	Installed cost ($, year)	: 685000 82
K.	New capacity cost ($/kW, year, FCR)	: 1000 82 18

Uprating Financial Analysis (1982$)

Year	Differential production savings	Value of capacity increase	Total savings	Present worth savings	Cumulative present worth savings
1983	$1,191,788	$2,799,360	$ 3,991,148	$ 3,501,007	$ 3,501,007
1984	1,287,131	2,799,360	4,086,491	3,144,422	6,645,430
1985	1,390,102	2,799,360	4,189,462	2,827,767	9,473,197
1986	1,501,310	2,799,360	4,300,670	2,546,342	12,019,539
1987	1,621,415	2,799,360	4,420,775	2,296,012	14,315,551
1988	1,751,128	2,799,360	4,550,488	2,073,141	16,388,692
1989	1,891,218	2,799,360	4,690,578	1,874,530	18,263,222
1990	2,042,516	2,799,360	4,841,876	1,697,363	19,960,586
1991	2,205,917	2,799,360	5,005,277	1,539,162	21,499,748
1992	2,382,390	2,799,360	5,181,750	1,397,745	22,897,493
1993	2,572,982	2,799,360	5,372,342	1,271,189	24,168,683
1994	2,778,820	2,799,360	5,578,180	1,157,802	25,326,485
1995	3,001,126	2,799,360	5,800,486	1,056,091	26,382,576
1996	3,241,216	2,799,360	6,040,576	964,740	27,347,316
1997	3,500,513	2,799,360	6,299,873	882,590	28,229,906
1998	3,780,554	2,799,360	6,579,914	808,617	29,038,522
1999	4,082,998	2,799,360	6,882,358	741,916	29,780,439
2000	4,409,638	2,799,360	7,208,998	681,691	30,462,130
2001	4,762,409	2,799,360	7,561,769	627,236	31,089,366
2002	5,143,402	2,799,360	7,942,762	577,929	31,667,295
2003	5,554,874	2,799,360	8,354,234	533,218	32,200,513
2004	5,999,264	2,799,360	8,798,624	492,615	32,693,129
2005	6,479,205	2,799,360	9,278,565	455,690	33,148,818
2006	6,997,542	2,799,360	9,796,902	422,058	33,570,876
2007	7,557,345	2,799,360	10,356,705	391,382	33,962,258
Total				$33,962,258	

Capital expenditure	: $ 685,000
Equivalent capital value of the present worth savings	: $27,452,525
Cost to benefit ratio	: 1:40.1

showing how the yearly savings figures in Table 3 were generated.

Differential Production Savings are the savings realized by displacing high cost generating capacity with lower cost generating capacity.

Formulas

Differential Production Savings (1983) = kWh/year X uprating percent X Differential Production Cost (1982) X $(1+F)^N$
where kWh = kW rating X hours/year X capacity factor
where F = Fuel cost escalation = .08
and where N = 1983-1982

The Differential Production Savings are tabulated for each year in Table 3.

Value of Capacity Increase is the amount of revenue for the capital expenditure that must be collected for each year of the plant life in order to pay for the cost of ownership (fixed charges).

Value of Capacity Increase = Estimated Purchased Price of New Capacity (1982) X Fixed charge rate
where Estimated Purchase Price of New Capacity (1982) = additional cost of kW capacity X New Capacity (1982) X $(1+i)^M$
where i = Financial discount rate = .14
and where M = 1982-1983

The Value of Capacity Increase is constant through the life of the investment because a levelized fixed charge rate is used.

Present Worth Savings is calculated by adding the Differential Production Savings and the Value of Capacity Increase.

Present Worth Savings (1982) = Total Savings(1983) X 1/(1+i) (1983-1982)
where Total Savings (1983) = Differential Production Savings (1983) + Value of Capacity Increase (1983)
and where i = Financial Discount Rate = .14

The savings for each year are present worthed to 1982 dollars and are summed (see Table 3).

Equivalent Capital Value of Present Worth Savings is determined by dividing the annualized savings by the fixed charge rate.

Equivalent Capital Value of Present Worth Savings (1982) = Cumulative Present Worth Savings X CRF (i,N) X 1/Fixed Charge Rate
where CRF = capital recovery factor (which annualized the savings at the finanical discount rate for the life of the investment) = .1454984.

A 40-to-1 savings

The capital expenditure is paid back after the first year of use. The equivalent capital value of the present worth savings, $27,452,525, is a staggering sum. The uprating realizes a 40-to-1 savings ratio, an overwhelming justification for a utility to commit its financial resources to the hydro modernization.
(Based on a paper presented at the annual meeting of the Pacific Coast Electrical Association, March, 1982)

C8650-4 12/15/82

Volume 60, Number 12
December 1982

09825 1957257 1 2046
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Incentive rate of return orders should specify how money costs are to be recovered, says NY regulator

Dan Utroska
Associate Editor

ALBANY, N.Y.—Incentive rates of return schemes being mandated or considered by public service commissions should be drafted to explicitly detail how companies building large power generation plants will be allowed to recover capital carrying costs in the future, a state regulator has said here.

According to New York commissioner Richard E. Schuler, if a commission implementing an incentive rate of return (IROR) spells out in advance the rules regarding how the state agency will treat ratepayer repayment of interest charges on borrowed construction money, then it will more fully provide a rate scheme that is less dependent on changing regulatory attitudes and more a function of utility management efficiency.

Schuler is generally credited with translating the incentive rate of return idea from the oil industry to the electric utility industry. Simply put, this incentive plan seeks to reward electric company shareholders if a utility can complete a power plant project for less than an established, agreed-upon cost target. Conversely, shareholders are penalized if a utility finishes plant construction above the target cost.

The New York Public Service Commission is the first state agency in the nation to actually implement such a scheme, although other jurisdications around the country are currently considering the idea in an effort to rein in runaway power plant construction costs (see *EL&P*, October, 1982, page 1). A target cost completion figure of

Continued on page 12

Reagan picks Interior's Hodel to succeed Edwards at Energy

WASHINGTON, D.C.—Quietly, and without much fanfare, Donald Hodel was sworn in as acting energy secretary early in November, succeeding James Edwards.

Unlike those who preceded him, Hodel is an expert on energy matters. For 6 years, he headed the Bonneville Power Administration.

Hodel, a 47-year old lawyer who was second in command at the Interior Department, immediately came under fire from environmental groups because of his friendship with Interior Secretary James Watt.

Denny Shaffer, Sierra Club president, said, "America does not need a second James Watt in the Cabinet."

Friends of the Earth said, "The symbolism of giving Watt's deputy a seat on the Cabinet is incredible."

Chairman of the House Energy Conservation and Power Subcommittee Rep. Richard Ottinger (D., N.Y.) said, "I hope the 'Under New Management' sign on the department means more than just the same old stew dished out by a new cook."

At press time, Hodel had not been permanently nominated for the appointment, but it was expected to occur during the lame-duck session of congress that began Nov.29.

White House spokesman Larry Speakes announced Hodel's appointment, but neither Hodel or Reagan was present.

Cherokee 2 & 3 cancelled

CHAROLETTE, NC—Add Cherokee Units 2 & 3 to the growing list of nuclear unit cancellations.

Duke Power Company Executive Vice-President W.H. Owen said the two 1280-MW units at the Cherokee Nuclear Plant in South Carolina were dropped because of "lower growth and demand than when initially planned. The need for these units has stretched out beyond our current planning horizons."

The utility had projected a 7 percent annual growth when the units were planned, but that has since declined to only 2 percent a year.

Approximately $68 million has been spent on both units. They were delayed in 1980 and 1981 because of reduced load growth, high interest rates and difficulty in attracting capital, said a Duke spokesman.

Duke says it will try and recover the costs through rate-increase requests.

Shortly after the cancellation decision, the North Carolina Utilities Commission granted the utility a $61.7 million rate increase. Last March, they had requested a $165.3 million increase.

Work continues on unit 1

According to Mary Cartwright, Duke spokesperson, work is continuing on Cherokee-1 at an "extremely slow pace." The company has spent $505 million on the 18 percent complete reactor. Only 140 workers are left at the construction site. In January 1981, about 1,800 workers were employed at the plant near Gaffney, South Carolina.

The utility said it will decide next year whether to go ahead with construction on Unit 1.

The three Cherokee units were part of a six reactor construction project initially designed to provide power for 1.3 million customers in the Carolinas. The other three reactors were cancelled last February.

Marble Hill rates to rise 85%, consultant calculates

NEW YORK, N.Y.—Aggregate electricity rates for all classes of Public Service Indiana customers will rise 85 percent over the period when the two Marble Hill nuclear units become operational, a utility analyst here has estimated.

This finding of Dr. Lewis Perl of the National Economic Research Associates, Inc. (NERA) has confirmed that this nuclear plant is one of the foremost candidates to experience the recently acknowledged phenomenon of "rate shock." One other nuclear plant that will experience this effect in a severe way is the Wolf Creek plant, being constructed jointly by Kansas City Power & Light and Kansas Gas & Electric (see *EL&P*, September 1982, page 3).

Both plants are being constructed in regulatory jurisdictions where prohibitions exist against collecting construction cost carrying charges from ratepayers during the building period, deferring such recovery until the plants are "used and useful." Such prohibitions against construction work in progress (CWIP) in rate base, which are in effect in only a minority of states, defer recovery costs until the plant becomes operational and then hit the ratepayer all at once.

Commissioned by the Indiana Public Service Commission to determine whether there was economic justification to continue construction of the Marble Hill plant, NERA's Dr. Perl concluded that there was such justification, provided construction cost escalations were not allowed to exceed more than 40 percent of the current $5.1 billion completion figure.

In accordance with this finding, Dr. Perl proposed that the PSC conduct an independent audit to determine if it was likely that the plant could be brought on-line for $5.1 billion. This proposal suggests the possible confluence of two recent regulatory developments in the Marble Hill case: rate shock and incentive rates of return (IROR).

If the commission decides that the plant can be completed for $5.1 billion, it may decide to implement somewhat stricter sanctions on utility management to assure that the cost target is achieved. By imposing an IROR, Public Service Company of Indiana shareholders would then be subject to a penalty if the target cost is exceeded. Indeed, in October, NERA proposed that the Indiana PSC think about a reward/penalty rate scheme for Marble Hill, and the commission currently is considering the idea.

The two-unit plant is being constructed by Public Service Company of Indiana, with a 17 percent ownership by the Wabash Valley Power Association, a group of rural electric cooperatives in nothern Indiana. Unit one is slightly over 40 percent complete, and unit 2 is nearing 30 percent. Startup dates are currently 1987 and 1988, respectively.

Interest is half of plant costs

Because the Marble Hill nuclear plant is being constructed in a jurisdiction that does not allow CWIP in rate base, about 45 percent of the total cost of the plant will be interest charges, James H. Pennington, vice president of financial operations at Public Service Company of Indiana told *EL&P*.

Exacerbating the company's financing situation is the fact it will have to go to the securities market for the rest of the money it needs to complete the plant. "We are at a point where we now are generating very little cash internally to finance construction," Pennington said.

Last August, Standard & Poor's lowered the company's securities ratings to BBB+, thereby signaling to potential investors that these securities were more risky and would require additional premiums.

Two major efforts are currently underway to relieve the company's rate shock problem. First, PSI says that it is mounting a vigorous effort in the state legislature to secure enabling legislation for CWIP in rate base. Although the Indiana PSC appears not

Continued on page 14